APPENDIX C

NDDH LETTER TO EPA DATED FEBRUARY 27, 2002

NORTH DAKOTA DEPARTMENT OF HEALTH
Environmental Health Section

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February 27, 2002

Mr. Richard Long (AP-AR)
Chief, Air Programs Branch
U.S. EPA Region VIII
999 18th Street, Suite 500
Denver, CO 80202-2466

Re: Acid Rain Database

Dear Mr. Long: Rich

This letter is to follow up discussions between the Department and Region VIII personnel regarding the use of Acid Rain Program data for determining compliance with State emission limits and the Prevention of Significant Deterioration (PSD) increments. An email provided to Kevin Golden on February 2, 2002 regarding this topic is also referenced. As we have stated previously, the Department believes that the data, especially before January 1, 2000, is not sufficiently accurate for these purposes.

The continuous emission monitors at all the power plants in North Dakota with the exception of Heskett Station Unit 1, are subject to the Acid Rain Program requirements. Coal Creek Station, Coyote Station, Antelope Valley Station, M.R. Young Station Unit 2 and Stanton Station Unit 10 are also subject to requirements under the New Source Performance Standards. The Acid Rain Program and New Source Performance Standards (NSPS) have different certification requirements. The New Source Performance Standards allow a relative accuracy of ± 20% and do not require a bias adjustment factor. The Acid Rain requirements include a relative accuracy of ± 10% and bias adjustment factor for those monitors that are reading lower than the applicable test method. A bias adjustment factor is not allowed if the monitor is reading higher than the test method. The Acid Rain requirements also require the source to substitute data into the database when the continuous emission monitors are out of service. The New Source Performance Standards do not require this substitution. In general, the substitution is punitive towards the source because it overstates the emission rate. The Department has allowed all sources to demonstrate compliance with short-term permit limits based on NSPS criteria.

Several of the power companies in North Dakota have experienced problems in accurately measuring the flow in the stack because of non-linear flow patterns (cyclonic flow). In response to this nationwide problem, EPA developed three new test methods to more accurately measure the flow. These test methods were generally not used until well into 1999. Based on conversations with industry, these flow discrepancies may have caused emissions to be over predicated by as much as 20%. The Department recognized this problem early after the continuous emission monitors were installed. Based on evidence supplied by Great River Energy, the Department allowed a different method for determining compliance with the State emission limits at Coal Creek Station.

This whole issue was the subject of a meeting in Washington, DC in October of last year. Although the meeting was specific to stationary gas turbines, the issues discussed are directly applicable to power plants in North Dakota. Enclosed is a summary of the topics that were discussed at that meeting. As you can see, many of the issues that we have brought up in the past were discussed at this meeting in addition to other relevant issues.

In summary, we believe that data from the 1999 Acid Rain database should not be used for determining compliance with non-acid rain emission limits or PSD Increments. This data is biased high and does not accurately portray the compliance status. The data before January 1, 2000 is less accurate than later data because of the flow measurement problems at various plants.

If you have any questions, please feel free to contact me.

Sincerely,

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:alm
Enc:
xc: Francis Schwindt, Chief, EHS

Stakeholders Input Regarding Streamlining Turbine Compliance October 9, 2001 at CAMD Office, Washington, DC

The following is a list of topic areas discussed at the meeting

I. Reporting Requirements under Part 75 and Part 60

Input provided in advance:

- Should sources be able to use Part 75 EDR as excess emission report for Part 60 compliance? Potential barriers include:
  - ✓ use of substitute data,
  - ✓ difficulties retrieving information from Part 75 records,
  - ✓ differences in reporting frequency,
  - ✓ averaging periods, and units of measure
- Agency should create consistent definitions of valid operating hours for Da, Db, GG and Part 75.
- Turbines that are low emitters and operate at specific loads, and do not use water to fuel injection, should not need to do a multi-load testing.

New Input:

- Objection to the use of substitute data for Part 75
  - Substitute data are "made up"and do not reflect true emissions from the source
  - Substitute data are acceptable for emissions trading programs, but not for compliance-related programs
  - Data submitted for Part 75 are bias-adjusted CEMS data, while Part 60 data are not adjusted. This is one difference to address in combining them.
  - Best data should be used for compliance purposes
- Variety of interpretations of Part 60 requirements by different states makes for greater complexity
  - State Interpretations of Part 60 vary, including of data validation. EPA should issue guidance. Pennsylvania has a document which was specifically useful and worthy of further investigation.
  - Work with states to standardize Part 60 reporting formats and requirements; develop a model rule or model electronic data reporting (EDR) format
  - Figure out how to get all states on board, work with states
  - OAQPS grants waivers and use of alternative methods on case-by-case basis; it may be useful to compile waivers into one document
  - Develop guidance on how sources can petition for a waiver under Part 60
  - Lead times for petitions are sometimes too long to able to include approved alternatives in the permit
  - It will be useful to provide guidance to state and regions, however, regulatory language may sometimes be necessary to get States on a more uniform basis
  - Some states require separate source compliance tests and RATAs; states need to understand that compliance can be determined using RATA data

- Applicability determinations should be incorporated into the rules.

- Different definitions in Part 60 and Part 75
  - Need consistent definitions that are used in both Part 60 and Part 75. Operating hour and day were of the greatest interest. It was generally agreed that any common definitions must consider original rationale
  - Operating day (24-hour rolling averages can be clock or operating hours)
  - Need to reconsider definition of peaking unit to allow greater utilization
  - Define three combustion turbine types: 1) baseload; 2) peaking; 3) non-baseload or peaker that exceeds utilization, e.g., "cycling" unit
  - Look at alternative definition of peaking units, perhaps based on total emissions per year
  - Fuel switching produces high emissions; definition of hour should be clarified for compliance or should be revised
- Start up and shut down
  - Periods and the treatment of this data should be evaluated: how do equations apply? (Part 75 and 60 treat source startup/shutdown periods differently)
  - Clarify how start up and shut down are included in averaging time
  - Keep the diluent cap in part 75. This prevents "run away" emissions due to diluent value in the denominator of equation to compute lb/mmBtu
  - Account for emissions during start up and shut down as opposed to limiting emissions during these times; count emission in total but don't have limits.
  - Interpretations for start up and shut down should include exemptions for dual fired units (units that switch fuels multiple times during operation)
  - Part 75 regulations do not effectively handle units that idle at 2 -3 MW
- Before making any changes to Part 60, need to consider the impact that changes to Part 60 may have on other sources, such as incinerators
- Subpart GG
  - Not applicable to new units because many new units do not have water injection. Even those that do, have emissions well below 100 ppm levels even when malfunctioning. What is the value of GG for such new units?
  - The datedness of subpart GG might be addressed by Establishing a cut-off date for subpart GG applicability
  - Some commenters questioned the value of multi-load testing on units without water injection under both Part 60 and 75?
  - Part 60 NSPS monitoring requirements didn't envision CEMS; suggest that units using CEMS just follow Part 75 requirements
  - The span requirement for 300 ppm for a monitor is no longer appropriate considering the low NO_x standards and available control technology

II. Continuous Monitoring Practices and Quality Assurance

Input provided in advance:

- Performance Specification
  - ✓ Flexibility to perform the 7 day drift test over consecutive operating days. Should this test be done for peaking units?
  - ✓ Part 60, App F, §60.8 and §60.13. Sources indicated that these requirements should be revised to eliminate the need of performance testing for pollutants which are being monitored by CEMS, since CEMS demonstrate compliance on a continuous basis.
  - ✓ Compliance certification tests for Part 60 and 75 compliance should be done at the same time.
- Sources required to perform linearity checks that are subject to Part 75 requirements should have Part 60 Cylinder Gas Audits requirements waived.
- Part 60 and Part 75 QA procedures need to be reviewed to assure that they are appropriate for low emitters, e.g., alternative relative accuracy and calibration error performance specs may be needed for low emitters
- Also for low emitters the enhanced importance of NO/NO_2 conversion efficiency variability and NO_2 absorption in water should be analyzed.
- Explore different ways to address start up emissions from peakers and low emitters in lieu of dual range monitors.
- Allow off-line calibration tests for extractive CEMS. Many new turbines use extractive CEMS to measure low concentration.
- Should Part 75 and Part 60 allow for PEMS for combustion turbines instead of CEMS?

New Input:

- 7-day drift test/calibration
  - Why is this test relevant, considering that CEMS are required to conduct a daily calibration check after certification?
  - Sometimes it is difficult to complete the 7-day drift test within certification period, especially for non-baseload units. Times need to be relaxed.
  - Off-line/on-line testing doesn't work for non-baseload, non-peaking units specially with fuel switching units (i.e., cycling units)
  - Off-line/on-line matters only for some dilution systems (i.e., dilution systems without temperature compensation), not a problem with non-dilution extractive systems. Off-line testing should be allowed. Other commenters indicated that there can be a problem with different flue gas temperatures for dilution systems that use an in-stack orifice
  - CEMS is likely to fail calibration error test the first day back on line after prolonged downtime; this is particularly an issue for peaking units
- Permits
  - Current regulations require a dual petition process should be unified
  - While there is flexibility in the time limit for compliance demonstration for Part 75, Part 60 has 60-day requirement; add more flexibility to Part 60
  - Harmonize recertification policies
  - Timing of case-by-case determinations and waivers should be linked to permits deadline to allow for deadline exemption during waiver review process
  - States should not be able to limit the option for extended time frames for testing

- Multiple deadlines associated with the start up and commencement of commercial operation should consider time for unit shake down

- Monitoring
  - PEMS should be allowed for Part 75 compliance
  - For catalytic combustion systems, PEMS may be better than CEMS; supporting data will be provided to CAMD
  - Difficult to certify PEMS which is restricting their application
  - There is a disparity in CO monitoring requirements between Part 60 and Part 75 which should be corrected
  - Some questioned the need for CO CEMS
  - Add Part 75 QA for CO monitors (e.g., apply NO_x procedure to CO monitors)
- QA
  - QA procedures need to consider start up issues (Partial operating day and partial hours can be a problem -- issue also related to averaging of hours)
- Part 60 prescriptive requirements applying to span, drift, selection of analyzer ranges for new units can be a problem
- Low-emitting units
  - For very low emitting units, Part 60 certification is difficult to achieve because relative accuracy requirement is tight and also leads to daily calibration errors failure

III. Reference Methods

Input provided in advance:

- Harmonize applications of Method 20 and Method 7E and make methods and more user-friendly
- Review available data to analyze if full traverses are necessary specifically for CTs with SCR controls and stratification in other configurations such as rectangular ducts
- Promulgate Conditional Test Method 27 (NH_3) so that RATAs for NH_3 CEMS can be performed
- NH_3 may be getting converted to NO_x or interfering with NO_x readings, especially for low emitters)

New Input:

- Methods 7E and 20

  Traverse point selection
  - Is the Method 20 requirement still useful (preliminary O_2 traverse conducted to determine the eight sampling points used for the test)? How many times does it needs to be repeated? Perhaps requirement can be dropped if the source demonstrates that no stratification exists at the test location; also, perhaps test can be done on just one stack in a groups of stacks in several identical units instead of on all the units.
  - Allow Part 75 tests to be used for Part 60.
  - Expand use of like kind test exemptions
- Ammonia
  - Many states require NH_3 testing and NH_3 CEMS.

- Simple and precise NH_3 method needed; Recommendation to look at EPRI method under development
- States requiring NH_3 CEMS need a better reference method for testing
- Low concentrations can be a problem; no NIST- or EPA Protocol 1-certified NH_3 calibration gas standards are available; EPRI is talking to gas suppliers about calibration gas issue
- Mass balances should be considered as an alternative to an NH_3 CEMS
- EPRI claims that draft Method 27 produces errors as high as 38%

- HAPS monitoring
  - Opposition to Combustion turbine MACT standards being developed for formaldehyde
  - There is a concern about the current test methods (CARB 430 or FTIR) performance.
  -
- Particulate
  - Some states are requiring that gas-fired CTs test for particulate. Guidance for measuring these low levels is needed.

IV. Standards and Compliance Alternatives

Input provided in advance:

- Combine Subpart Da and GG emission limits for combined cycle units
- CEMS based compliance information should be adequate for demonstrating Part 60 compliance and provide a waiver from water to fuel ratio monitoring. There is also a question associated regarding what percentage monitor availability should be recommended in this case.
- Drop Subpart GG fuel bound nitrogen monitoring requirements for natural gas
- Drop Subpart GG fuel sulfur monitoring requirements for natural gas
- Alternatively, in Subpart GG, exempt sources from the fuel monitoring for units burning pipeline quality natural gas, indicating that the sulfur and nitrogen content in gas are very low and test are cumbersome
- Need to simplify Part 75 reporting for low emitters
- Evaluate the need for ISO correction in new state, local, or PSD regulations
- CTs should be able to use Part 75, App D to certify gas-fired units under NSPS
- CTs that are peakers should be required to test during winter time
- Monitoring exceptions for start up and shut down periods

New Input:

- Flow monitoring
  - States should allow fuel flow monitoring as described Appendix D of Part 75 as an option
- Sampling locations
  - Subparts Da and GG combination require testing at two locations because there are two combustion units with two separate standards. While Da has been fixed, Subpart GG has not. Also need to fix this for Subpart Db.
- Fuel nitrogen and sulfur
  - Delete *Part 60* fuel analysis for nitrogen if NO_x CEMS installed

- Delete *Part 60* sulfur monitoring requirement for natural gas
- Rely on AP-42 to show nitrogen content in fuels
- Fuel monitoring requirements should be retained for oil

- ISO corrections should be eliminated *in Part 60*
- Timing of compliance testing
  - Compliance tests should be scheduled for when a unit is up and operating; testing and grid demand should be coordinated when possible
  - Summer peaking units should not be required to test during winter
- Put PEMS on peaking units
- Make NO_x CEMS an option, not a requirement for Part 75 CTs

V. Miscellaneous Issues

Input provided in advance:

- Need to explore stability of calibration gases in the sub-ppm concentration range
- Low-level NO calibration gases are available in EPA Region 9, but are expensive and seem not to be available in other regions; need to explore the extent of the problem
- Need turbine-specific CEMS certification guidance

New Input:

- Harmonize recertification
  - Avoids need for dual (Parts 60 and 75) petitions for extensions for time
  - Schedule RATAs under Part 60 and Part 75 at same time
  - Could this be part of a consolidated rule for sources to opt in?
- Is monitoring necessary for very low-emitting units?
- Use a common EDR format for all reporting
- Availability of low-level NO cylinder gases is no longer a problem
- Compile all regional regulatory applicability determinations in one document that will apply in all regions

How To Improve the Process

- If it is broke, be sure that the cure is not worse than the disease
- Need to get state involvement and buy in to make changes work
- Streamline case-by-case approvals (look at the delegation of authority as possible streamlining approach)
- Look at how EPA introduced the new volumetric flow methods 2G, 2F, and 2H, an duse it as an example of interaction among different areas of the Agency.
- Should revisions be made piece-meal or as part of a consolidated rule? The latter approach will reduce compliance and implementation costs, but could unacceptably delay action. Action is needed.
- Query states to identify if there are other ~~on~~ examples of situations where Part 75 would cause a Part 60 compliance problem
- Consider prospective changes if retroactive would be too disruptive
- For quick action, changes should be emissions neutral (i.e. those which result in no net increase

in emissions, but merely simplify compliance)

APPENDIX D

DAKOTA GAS LETTER TO NDDH
DATED SEPTEMBER 7, 2001

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC SUBSIDIARY

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September 7, 2001

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
1200 Missouri Ave.
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Bismarck, ND 58504-5264

Re: Response to July 11, 2001 Letter Regarding Class I Increment Modeling

Dear Mr. O'Clair:

This letter responds to the North Dakota Department of Health (**Department**) letter of July 11, 2001, to Mr. Ron Harper of Dakota Gasification Company (**DGC**), inviting comments on the Department's plans to model SO_2 increment consumption in Class I areas, and the intent of the Department to treat all emissions from DGC's Great Plains Synfuels Plant as Class I increment consuming. DGC respectfully offers the following comments.

The variance granted in 1993 for a major modification of the synfuels plant was then and continues to be valid. The modification is exempt from the requirement that it not cause or contribute to a Class I increment exceedance. Because the major modification is exempt from this requirement, it is also exempt from modeling intended to test compliance with the requirement.

Given the precedent of how Class I impacts have been addressed in North Dakota over the past two decades and the absence of any empirical evidence of adverse effects on air quality related values (**AQRVs**) in Class I areas, there does not appear to be any justification for modeling SO_2 impacts on those Class I areas at this time.

<u>I. Overview of Class I Increments and Variances</u>

The Prevention of Significant Deterioration (**PSD**) increments for sulfur dioxide were first defined in the Clean Air Act Amendments of 1977 (Pub.L. 95-95). These increments work in tandem with "air quality-related values" (**AQRVs**). Federal Land Managers (**FLMs**) have a responsibility to protect AQRVs in Class I areas and to consider, in consultation with the Environmental Protection Agency (**EPA**), whether any proposed major source or major modification will have an adverse impact on such values. Clean Air Act § 165(d)(2)(B), 42 U.S.C. § 7475(d)(2)(B).

Class I increments provide a means for protecting AQRVs, and a method to determine who has the burden of proof as to whether or not a proposed project

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will adversely impact AQRVs. If the FLM demonstrates to the satisfaction of the State that the proposed source will have an adverse impact on AQRVs, a permit will not be issued even if the Class I increment is not exceeded. If the FLM makes the determination that the source will not have an adverse impact on AQRVs, a permit may be issued even if the Class I increment is exceeded. Clean Air Act § 165(d)(2)(C), 42 U.S.C. § 7475(d)(2)(C); NDAC § 33-15-15-01.4.j. This latter situation is referred to as a "variance" in EPA regulations. 40 CFR § 51.166(p)(4); *see also* NDAC § 33-15-15-01.4.j (4).

The Class I increments and AQRVs are intended "to provide additional protection for air quality in areas where the Federal Government has a special stewardship to protect the natural values of a national resource. Such areas are the federally-owned Class I areas under the [Clean Air Act]." S.Rep. 95-127, 95th Cong. 1st Sess., at 34 (May 10, 1977). It is AQRVs, however, which have primacy in decisions regarding the protection of Class I areas. The Class I increments were described by Congress as "a flexible test . . . for determining where the burden of proof lies and is an index of changes in air quality. It is not the final determinant for approval or disapproval of the permit application." *Id.*, at 35. "[T]he term 'air quality related values' of Federal lands designated as Class I areas includes the fundamental purposes for which such lands have been established and preserved by the Congress and the responsible Federal agency. For example, under the 1916 Organic Act to establish the National Park Service (16 U.S.C. Section 1), the purpose of such national park lands 'is to conserve the scenery and the natural historic objects and the wildlife therein and to provide for the enjoyment of the same in such manner and by such means as will leave them unimpaired for the enjoyment of future generations.'" *Id.*, at 36.

Additional legislative history reinforces the primacy of AQRVs. *See*, comments of Senator Muskie, Congressional Record, Vol. 123, p. 18464: "Even if technically there may be a violation of the Class I increments within the park area, the people who propose to build a plant can apply for consideration of the application for a permit on the basis that the damage would be to air quality values nonexistent (sic). So there is opportunity and some flexibility even close to some of these Class I areas which the bill seeks to protect. . . . Obviously if we set Federal standards there is some responsibility at the Federal level. The Federal decision makers are also bound to consider the provisions for flexibility which are written into the statute, and we would expect them to be so bound."

As provided in the Clean Air Act and the legislative history, the principal mandate in Class I areas is to protect AQRVs, not the Class I increments. The Class I increment is a means to an end--the protection of AQRVs. Class I increments are not inflexible standards that must be met in all cases; rather, they are a starting point which determines where the burden of proof lies. If an increment is met, the FLM must convince the State that AQRVs are adversely impacted to justify denial of a permit, whereas, if an increment is not met, the source must convince the FLM that AQRVs are not adversely impacted for a permit to be granted. In both cases, the ultimate determinant is AQRVs.

II. Analysis of EPA's Recently Announced Position Regarding Treatment of PSD Variances in North Dakota

In North Dakota, there have been a series of variances granted for projects which modeling predicted would result in increments in Class I areas being exceeded, but which were found by the FLM not to have an adverse impact on AQRVs. Despite these variances, EPA Region 8 recently has stated, for the first time, that, notwithstanding the statutory provision for variances, "the State is still required to correct the Class I increment violation through a revision to the SIP in accordance with the requirements of 40 CFR 51.166(a)(3)." Draft Technical Support Document for 2000 North Dakota SIP call, at 10; *see also*, Letter of February 1, 2000 from Richard Long, EPA Region 8 to Jeffrey Burgess of the Department.

Essentially, EPA asserts that a variance is not a variance. EPA's position is inconsistent with the statute, with its own long-standing practice, and erroneously interprets the Clean Air Act .

First, EPA may make a State Implementation Plan (**SIP**) call only if there is a finding that a SIP "is substantially inadequate to . . . comply with any requirement of this chapter . . . ." Clean Air Act, Section 110(k)(5), 42 U.S.C. §7410(k)(5). However, where a variance is granted, there is no failure to comply with any requirement of the Act. The modeled increment violation has been excused because there is no adverse impact on AQRVs, and thus there is no event of noncompliance to be corrected by a SIP call. This is corroborated by Section 165(d)(2)(C)(iv) of the Clean Air Act, 42 U.S.C. § 7475(d)(2)(C)(iv), which states that when a variance is granted for a Class I increment exceedance, the variance source becomes subject to an alternative maximum allowable increase in ambient pollutant concentration. *See also*, NDAC § 33-15-15-01.4.j(4)(b). This is an explicit recognition that facilities which have been granted variances are subject to the alternative maximums, not to Class I increments. Thus, for variance facilities, SIPs need only contain provisions assuring they do not contribute to the alternative maximum. Under the express terms of the statute, such facilities are exempt from compliance with Class I increments, and thus should not be subjected to modeling which tests compliance with those increments.

Second, Region 8's position, if valid, would effectively nullify the variance provisions of Section 165(d) from the Clean Air Act. If every time a variance was granted the State had to make a SIP change to eliminate the modeled increment exceedance, the variance would be meaningless. The SIP change would cure the exceedance, making the variance moot. Under EPA's interpretation, a variance, at most, would be a temporary device to allow a project to go forward while awaiting a SIP revision. But if variances were intended to be temporary only, Congress would have so provided. It did not. EPA cannot, by means of a new interpretation, amend the Clean Air Act.

Third, EPA's position would make the Class I increments the ultimate determining factor, whereas the statutory scheme and legislative history make it clear that AQRVs are the determinative factor. EPA fails to acknowledge that, in the absence of an adverse impact on AQRVs, there is no underlying reason to be concerned about the modeled status of a Class I increment. The increment is a means to an end, the starting point which defines the burden of proof concerning AQRVs; it is not the "final determinant".

Fourth, EPA's long-standing practice contradicts its newly-announced interpretation.

The only authority Region 8 cites in support of its position is the case of *Alabama Power v. Costle*, 636 F.2d 323, 363 (D.C. Cir. 1979). In that case, industry petitioners argued against the provision in EPA's regulations which authorized the agency to make SIP calls based on increment violations. Industry argued that the PSD permitting program was the exclusive mechanism for protecting increments, but the court rejected the argument. Numerous events might contribute to increment exceedances, but might not be subject to PSD permitting, and therefore, said the court, SIP calls are warranted to address increment violations. One of industry's arguments was that the statute provides for waivers of Class I increments which, conceivably, "could allow increments to be exceeded." The court responded that "[t]he waiver has vitality and recognition in that facilities granted special consideration under these provisions are, in effect, treated as facilities operating in compliance with the provisions of the Act. But the totality of facilities in compliance, as a group, may be subject to measures necessary to cope with a condition of pollutants exceeding the PSD maximum." 636 F.2d at 363. This is the language upon which Region 8 places exclusive reliance.

There are three important points to be made concerning this language. First, it is not mandatory. The court merely said that, where there are waivers (variances), the "totality of facilities" "may" be subject to measures to deal with exceedances of the PSD increment. It did not say that increment exceedances in variance situations "shall" be subject to SIP calls, or when or under what conditions such SIP calls might be warranted. Second, the language is *obiter dicta*, not essential to the court's holding. The court did not have before it a variance situation such as the one in North Dakota, the issues facing North Dakota were not briefed to the court, and therefore the court's tentative statement does not have the force of law. Third, nothing in the court's language says that variances are not valid or that the variance granted to a specific source can be subsequently revoked by means of a SIP call. The court expressly acknowledged that variances granted to sources have "vitality and recognition." At most, although DGC does not concede the point, the court's *dicta* might be read as tentatively authorizing <u>other</u> facilities ("the totality of facilities") to be subjected to a SIP revision. EPA's new interpretation, on the other hand, would deny to variance sources the vitality and recognition afforded by the court.

III. EPA's New Interpretation Is Inconsistent with Almost Two Decades of Agency Practice

EPA's newly-announced interpretation regarding Class I PSD variances is contradicted by an almost twenty-year history of contrary agency practice. EPA cannot now credibly claim that a variance is not a variance. EPA's past actions in North Dakota specifically contradict its current attempt to reverse field.

On September 20, 1982, the Department of the Interior (**DOI**) published in the Federal Register its certification that five North Dakota proposed sources would not adversely impact AQRVs in Class I areas, despite model predicted exceedances of the 3-hour and 24-hour SO_2 increments in the Theodore Roosevelt National Park (**TRNP**) North and South Units and the 24-hour increment in the TRNP Elkhorn Ranch unit and the Lostwood Wilderness Area (**LWA**). 47 FR 41480. In granting a variance for these sources, the DOI noted that the model-predicted exceedances of the increments even if these new sources were not permitted. The worst case estimate of maximum SO_2 concentrations from all sources would affect only two sensitive species of lichen, with minimal impacts on the lichen. A visibility analysis found no significant impact. A field evaluation showed no injury to sensitive species from air pollution. DOI found no adverse effects on AQRVs that would impair ecosystems, impair the quality of visitors' experience, or diminish the national significance of the Class I areas. DOI did <u>not</u> say that, despite the variance, North Dakota would have to revise its SIP to cure the modeled exceedances. Rather, it said that "[n]ew applicants must demonstrate to the Federal Land Manager's satisfaction that the proposed source will not cause or contribute to an adverse impact on the resources of Theodore Roosevelt NP and the wilderness portion of Lostwood NWR." The fact that DOI expected future applicants would have to demonstrate no adverse impacts on Class I areas indicates it did not expect there would be a SIP revision in the meantime which might cure the modeled exceedance and possibly make variances unnecessary.

An EPA guidance memo dated August 23, 1982 commented on these North Dakota variances and predicted that the process followed by the DOI "will in all likelihood serve as a model for future determinations and is consequently worth of note." The guidance memo did not even hint that EPA might require a SIP revision to cure the increment exceedances.

On September 27, 1984, the DOI granted a variance for a proposed natural gas processing facility, despite modeled predictions that the facility would significantly contribute to exceedances of the 24-hour Class I increment for SO_2 in the TRNP North Unit. 49 FR 38197. Pollutant levels were found to be below the threshold values for adverse impacts on sensitive plant and animal species in the park. A field evaluation found no symptoms of visible injury due to ambient air pollution.

On March 12, 1993, the DOI granted a variance for a major modification to the Great Plains Synfuels Plant despite modeled predictions that the modified facility would significantly contribute to exceedances of the 3-hr and 24-hr SO_2 Class I increments at TRNP and the 24-hour increment at LWA NWR. 58 FR 13639. The DOI found that the increase in allowable emissions would not increase visibility impacts; that there was no evidence of existing air quality impacts on biological resources at TRNP or LWA; that air quality in North Dakota had improved since 1984; and that the modification would not cause or contribute to impairment of ecosystems or the quality of visitor experience, or to a diminution of the national significance of the Class I areas. As with the 1982 and 1984 variances, there was no indication that North Dakota was expected to revise its SIP to correct the modeled exceedances of Class I increments.

Thus, on three occasions between 1982 and 1993, modeling predicted exceedances of the Class I SO_2 increments. At no time in the nineteen years since 1982 has there been a whisper from the EPA that North Dakota had to revise its SIP to address these exceedances. EPA's protracted silence during these years is powerful evidence that the agency understood that variances were, indeed, variances--that they were intended by Congress to excuse modeled increment exceedances, not to be temporary dispensations pending SIP revisions. It is powerful evidence that EPA understood that AQRVs, not increments, are the determining factor in Class I areas. It is powerful evidence that EPA understood that when AQRVs are protected there is no rational basis for SIP calls. In light of its long-standing practice, there is no justification for EPA to attempt to invalidate previously granted variances at this time.

IV. Dakota Gasification Requests the Department to Re-examine Whether Further Modeling is Necessary or Appropriate at this Time

In addition to the particular issue of the validity of the DGC variance, we believe there is a broader, but closely related, issue that would be appropriate for the Department to consider. That issue is whether there is any reasonable need or justification at this time for a SIP revision, or for additional modeling to determine the need for a SIP revision. We submit there is no such justification because: (1) in 1993 it was determined that air pollution was not having a significant adverse effect on AQRVs in North Dakota's Class I areas; (2) monitoring of SO_2 levels in and near Class I areas has not shown any significant increase in SO_2 concentrations or deterioration of air quality since 1993; (3) the lack of adverse impacts on AQRVs in North Dakota's Class I areas has been reaffirmed repeatedly despite the fact that modeling has predicted increment exceedances since 1982; and (4) it is AQRVs, not increments, which are the primary measure and diagnostic determinant of whether air quality is acceptable or unacceptable in Class I areas.

In light of these facts and two decades of precedent indicating there is no need for a SIP revision respecting SO_2 levels in Class I areas. Even if modeling were performed and predicted increment exceedances, to pursue a SIP revision based on modeled exceedances would be to ignore the absence of any empirical data indicating that SO_2 concentrations in Class I areas are a problem and to ignore the FLM determination of no adverse impact on the AQRV in the pertinent Class I areas in the state It is inappropriate for EPA to reinvent its long-standing interpretation and practice respecting this issue.

We thank you for the opportunity to comment, and look forward to hearing from you. We can be available at your convenience to discuss these issues further.

Sincerely,

Deborah F. Levchak
Staff Counsel

cc: Francis J. Schwindt
Lyle Whitham